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Regaining Oil Production by Overcoming Emulsion Problems After Artificial Lift Installation

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Abstract

An oil well, referred to in this paper as Well B, experienced a serious emulsion problem soon after the introduction of artificial lift using a hydraulic jet pump. This forced the operator to reduce the production rate to meet sales oil specifications. During its natural flow production period, this well experienced relatively emulsion-free operation. Consequently, the operator continued to use the same demulsifier, after the jet pump production began.

This paper presents results of a number of field trials that took place over 1.5-year period to control emulsions and to improve oil production. Initially, the operator raised the separator temperature but this was not effective. Next, the operator injected xylene into the formation. Although this was reasonably successful, the effect was short-term. It became necessary to open the separator dump valve to drain the emulsions, and reduce the basic sediment and water (BS&W). This expensive operation was only undertaken to maintain production. The operator then explored changing the demulsifier dosage rate and changing the location of the demulsifier injection port, but neither measure was effective. Finally, a series of bottle tests were conducted to find a better demulsifier to replace the original chemical, which was no longer effective. Soon after injection of the new demulsifier, the emulsions disappeared, and the operator regained the production rate.

Based on the field observations and the preliminary laboratory investigations, the emulsions that affected Well B over a period of 1.5 years were most likely caused by the introduction of artificial lift augmented by the continued use of the original demulsifier chemical, the increased production rate, and the presence of asphaltene and clay particles. An important lesson learned from this project was that emulsion treatment programs should be reviewed periodically, especially when operating conditions change.

Introduction

In Field M, Well B ceased to flow naturally in April 2014. It was then put onto artificial lift using a hydraulic jet pump in July 2014. Soon after jet pump operations began, a large amount of emulsion was found both in the separator and stock tank. Consequently, the sales oil failed to satisfy shipping specifications, even though the demulsifier being utilized had worked successfully during the natural flow production period.

from 2008 to 2014. The operator was forced to reduce the oil production rate from 50 to 35 m³/d to guarantee longer retention time and to reduce shear condition through the jet pump production system to improve the oil-water separation efficiency.

A multi-disciplinary team was set up, comprising members from the Production Engineering Department and the Technical Research Center to investigate the emulsion problems and find solutions to allow Well B to be produced at its target rate of 50 m³/d.

In this paper, we describe a number of field trials which took place over a 1.5-year period, their findings, as well as the ultimate solution that was implemented. Our efforts involved raising the separator temperature, injecting xylene into the formation, frequent openings of the separator dump valve, increasing the demulsifier dosage rate, changing location of the demulsifier injection port, and finally formulating a new demulsifier specifically for this well.

Field Description

Field M, located onshore Japan, has two wells (Well A and Well B). Both wells produce oil from a sandstone reservoir at a depth of approximately 3,500 m. This paper describes a case study of Well B. Emulsion was identified in the separator and stock tank during Well B's well testing at the time of its discovery. By the time Well B was put into commercial production in 2008, the operator had built a heat exchanger, a four-phase separator (oil, gas, water, and emulsion/asphaltene), and a vertical gun-barrel separator to process Well B's production fluid. To further increase the efficiency of oil-water separation, a demulsifier (Demulsifier A-1) was injected at the wellhead from production startup. **Fig. 1** shows the results from a bottle test conducted early 2008, from which Demulsifier A-1 can clearly be identified as the best performing chemical. **Fig. 1** also suggests that emulsion would form without chemical injection.

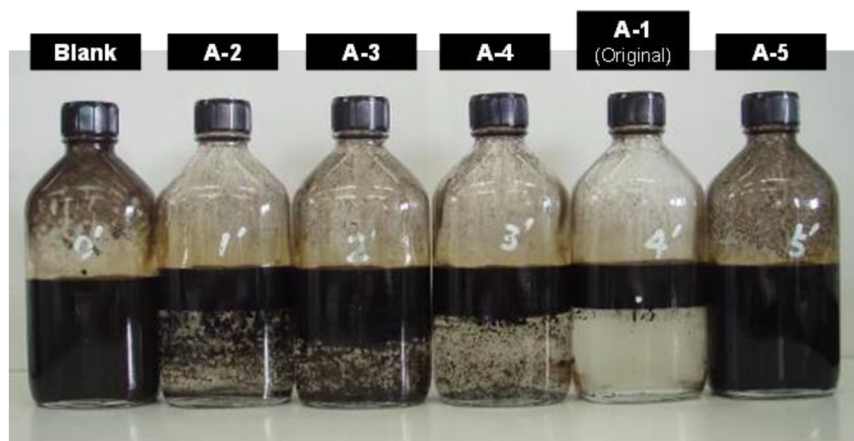


Figure 1—Photograph of the bottle tests result carried out in 2008. Demulsifier A-1 was the best performing chemical at natural flow, while emulsion was observed in the blank sample.

Well A's production fluid is processed at another processing plant; therefore, this production facility is dedicated to processing Well B's production fluid. During the natural flow production period spanning six years, the operator experienced relatively emulsion-free operation. Consequently, the operator considered the demulsifier effective and continued to use the same chemical after jet pump production began.

In addition to demulsifier, the operator also injected an asphaltene inhibitor at Well B's wellhead since production commencement, as nearby Well A experienced a significant asphaltene problem from production startup. While asphaltene is known to stabilize emulsions, effectiveness of the asphaltene inhibitor to Well B's emulsion is unclear and it is therefore, currently under investigation. The two chemicals used for Well B, namely the demulsifier and the asphaltene inhibitor, are compatible; no precipitation occurs when the two

chemicals are mixed. No other chemicals were used for Well B. A history of Field M's production problems related to asphaltene is detailed in [Uetani et al. \(2016\)](#).

Well B's target oil rate was restricted to between 30 and 35 m³/d during most of its natural flow production period, which was lower than its maximum production capacity. The reason for the rate restriction was based on Well A's operational experience. The operator learned from Well A that a stable production could be maintained without serious asphaltene deposition problems for a relatively long term by restricting the target rate to between 30 and 35 m³/d.

Well B's associated water cut ranged from 1.5 to 7%. Even though the water cut has gradually increased since the production start-up, this is not considered as the root cause of emulsion formation because the water cut remained unchanged after the jet pump installation at approximately 5.5%. The fluid properties of oil and water from this well are summarized in [Tables A-1 and A-2 \(Appendix\)](#).

In early 2013, Well B's flowing bottomhole pressure fell below the laboratory measured asphaltene onset pressure (AOP) of 3,410 psia. Despite this, the well productivity did not drop from 2013 to 2014. This suggested that precipitation of asphaltene had not caused serious formation damage in Well B. Hence, the operator decided to increase the well target rate to 50 m³/d as soon as jet pump operation began. The details of Well B's production history during the period of 2013 and 2014 are provided in [Uetani \(2014\)](#).

After Well B stopped flowing naturally in April 2014, production was restarted after installation of a hydraulic jet pump system in July 2014. The jet pump was installed inside 1.75-in coiled tubing (CT), while the CT was set inside 3.5-in production tubing (PT), with the jet pump placed close to the production intervals. Stock tank oil is used as the power fluid, which is pressurized and injected through the CT. The power fluid travels downhole through the jet pump nozzle. As the fluid pressure is reduced under the Venturi effect, the reservoir fluid is drawn into the pump throat, where the two fluids combine. This commingled fluid returns to the surface through the annulus between the 1.75-in CT and the 3.5-in PT. A schematic of the jet pump system is shown in [Fig. 2](#). It is envisaged that fluid undergoes relatively high shear environment through the jet pump (nozzle and mixing tube)

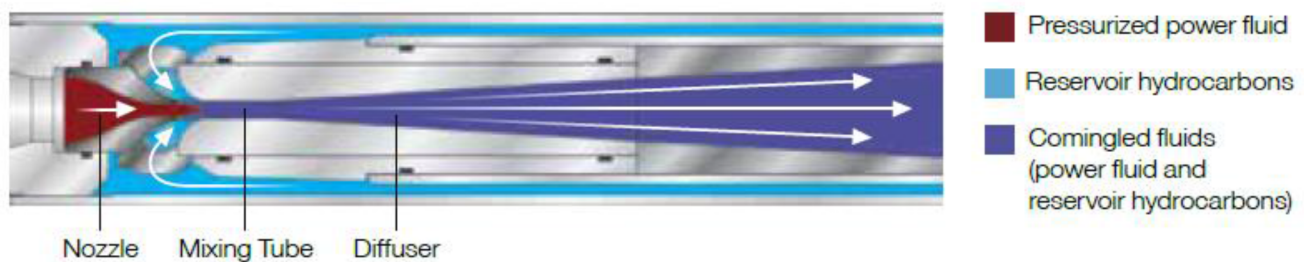


Figure 2—Schematic of a jet pump ([Weatherford 2016](#))

Emulsion Problems

Approximately two months after Well B began jet pump operation, and shortly after the production rates were increased to 50 m³/d, the oil-water separation quality dropped sharply. A large amount of emulsion was observed inside both the separator and stock tank. The emulsions were stable for days and proved difficult to break. The BS&W content in the sales oil exceeded the specification of 0.5 vol%.

In order to manage both the amount of emulsion produced and the retention time required for oil and water to separate, the operator was forced to reduce the production rate from 50 back to 35 m³/d. The amount of emulsion produced appeared dependent on the production rate, as shown in [Fig. 3](#). The photograph shows the two oil samples collected from the same location (downstream of the heat exchanger, but upstream of the separator) on the same day under production rates of 35 and 50 m³/d. Prior to sampling, demulsifier injection was suspended for a few days to ensure both samples were demulsifier-free.

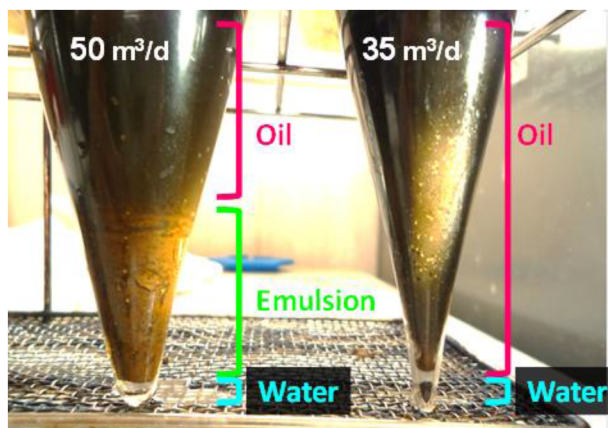


Figure 3—The higher the production rate, the greater the amount of emulsions observed at the surface during jet pump operation. Comparison of two oil samples collected at the same location under an oil production rate of 50 m³/d (left) and 35 m³/d (right). A large amount of emulsion was present in the 50 m³/d sample, while no apparent emulsion was observed in the 35 m³/d sample.

The relationship between emulsions and jet pump production remains unclear. However, it is very clear that the well completion configuration drastically changed during the switch from natural flow production to jet pump production, as illustrated in Fig. 4.

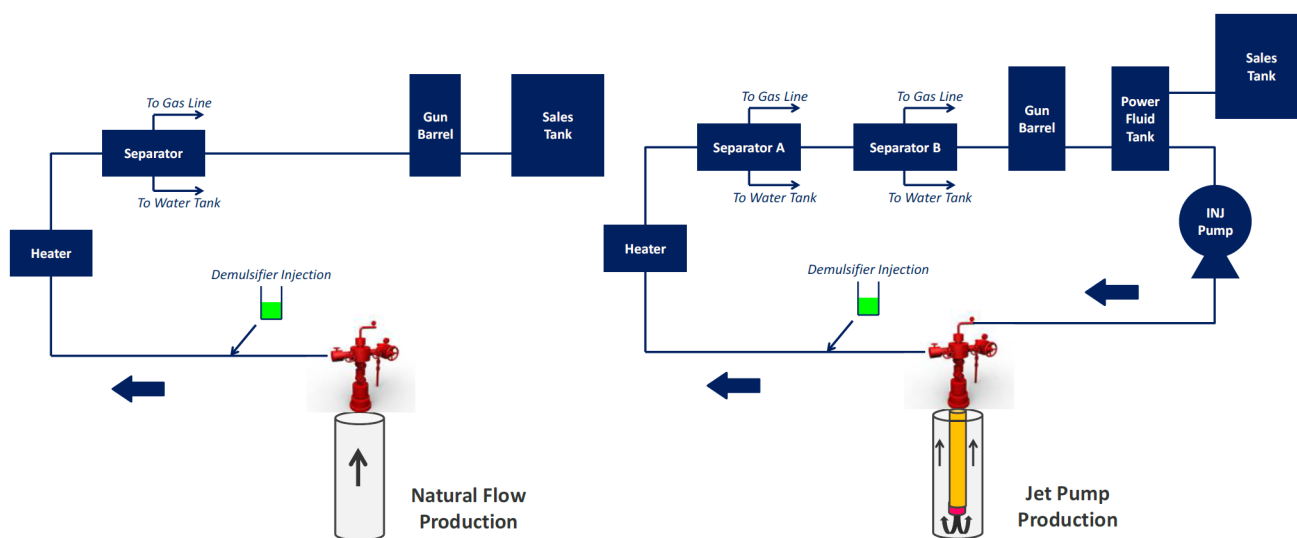


Figure 4—Simplified production flow configurations of the natural flow production scheme (left) and the jet pump production scheme (right). The second separator was installed during the jet pump installation to reduce benzene evaporation from the sales tank and to reduce calorific value of gas, which is used as fuel for the gas engine to operate the power fluid's injection pump.

The average oil velocity in the 1.75-in CT-3.5-in PT annulus (during jet pump production) was approximately four times higher than in the 3.5-in PT (during natural flow production) under the same oil production rates, as illustrated in Fig. 5. Two factors are responsible for this large difference. First, the rate of the fluid flow in the annulus is greater than that in the PT, because the production fluid from the reservoir and the power fluid travel as commingled fluids through the annulus. Power fluid rates required to achieve 35 and 50 m³/d of oil production are approximately 65 and 75 m³/d, respectively. Second, the cross-sectional area in the annulus (28 cm²) is smaller than the 3.5-in pipe (43 cm²).

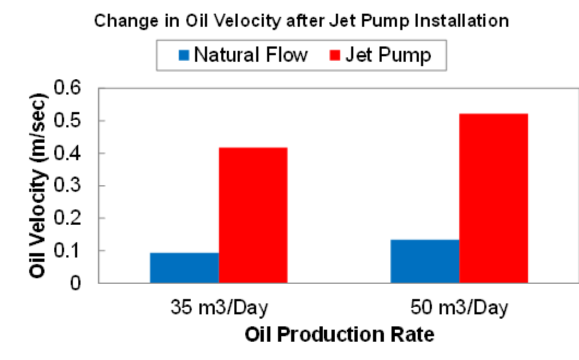


Figure 5—Comparison of estimated average oil velocities between natural flow and jet pump productions at various oil production rates.

The following equations were used to estimate average oil velocity in this study, after Bourgoune et al. (1991).

$$v_p = \frac{17.16q}{d^2} \quad (1)$$

$$v_a = \frac{17.16q}{d_2^2 - d_1^2} \quad (2)$$

where v_p is the average velocity (ft/sec) in the pipe, v_a is the average velocity (ft/sec) in the annulus, q is the flow rate (bbl/min), d is the internal diameter of the pipe (inch), d_2 is the internal diameter of the outer pipe (inch), and d_1 is the external diameter of the inner pipe (inch). For this study, 2.922 inches was used for d and d_2 , while 1.75 inches was used for d_1 . In all four production cases (various production rates and schemes), the Reynolds numbers exceeded 15,000, which indicates that the flow was turbulent (Economides et al. 1994).

Well A, which also has been produced using a jet pump since natural flow ended, also has experienced some emulsion problems in the past. However, the magnitude of these issues is not as serious as for Well B. In contrast, Well A has experienced more serious formation damage, caused by asphaltene deposition, as outlined in Uetani et al (2016).

Preliminary Analysis of Emulsion

As comprehensive laboratory investigation of the emulsions from Well B is currently in progress, only a preliminary analysis is provided in this section. Micrographic observations using fluorescence suggest that emulsions collected from the water tank were a water-in-oil type, as illustrated in Fig. 6.

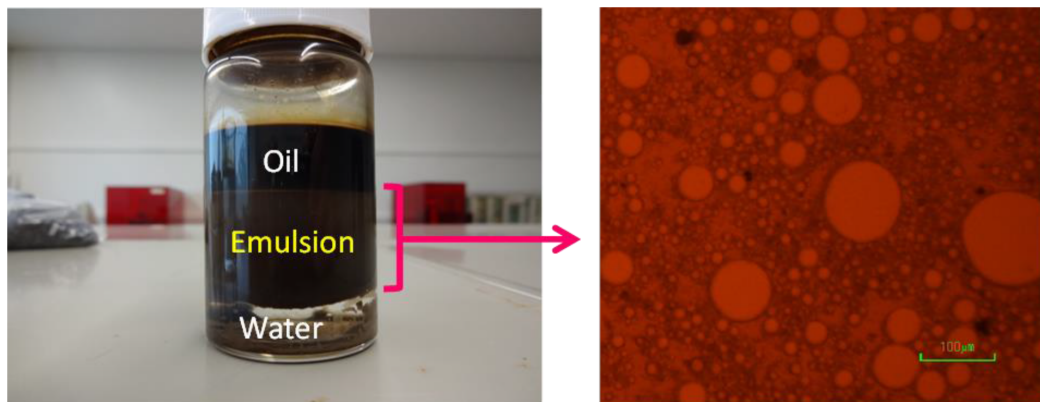


Figure 6—Photograph of the fluid sample collected from the water tank (left) and micrographic view of the emulsion phase (right).

Fig. 7 illustrates a water droplet-size distribution generated from the micrographic image shown above. Given that the mode of this distribution is approximately 5 μm , we categorized Well B's emulsions as 'tight', after [Kokal \(2006\)](#).

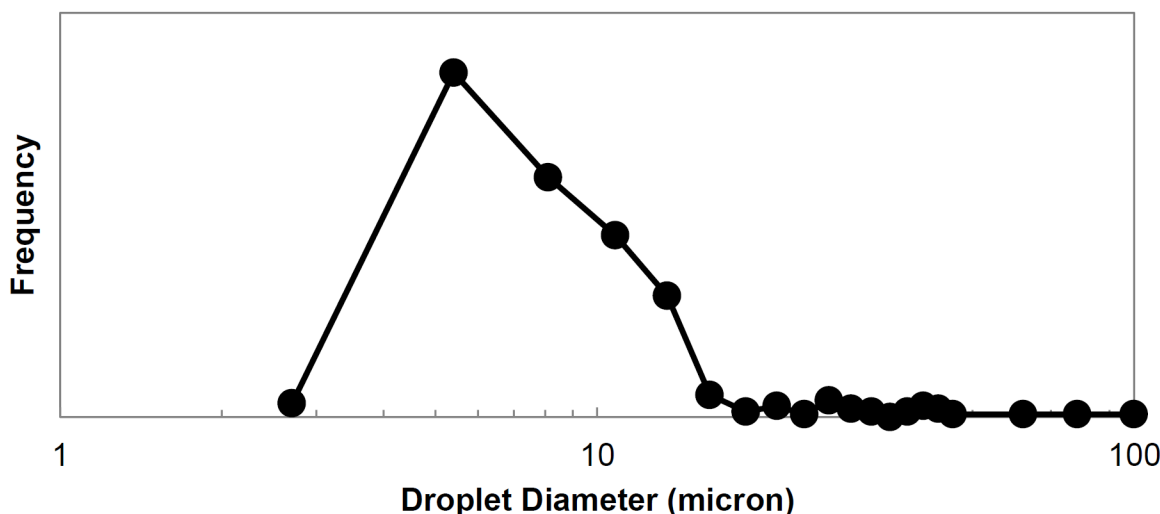


Figure 7—Droplet-size distribution of Well B's emulsions based on micrograph observations.

Asphaltene and clay particles were found in the emulsions collected from the water tank after filtering, (**Fig. 8**). Both particle types are known to promote and stabilize petroleum emulsions ([Schramm 1992](#), [Kokal 2005](#), and [Poindexter et al. 2005](#)). The effect of asphaltene and clay on Well B's emulsion is currently under investigation.

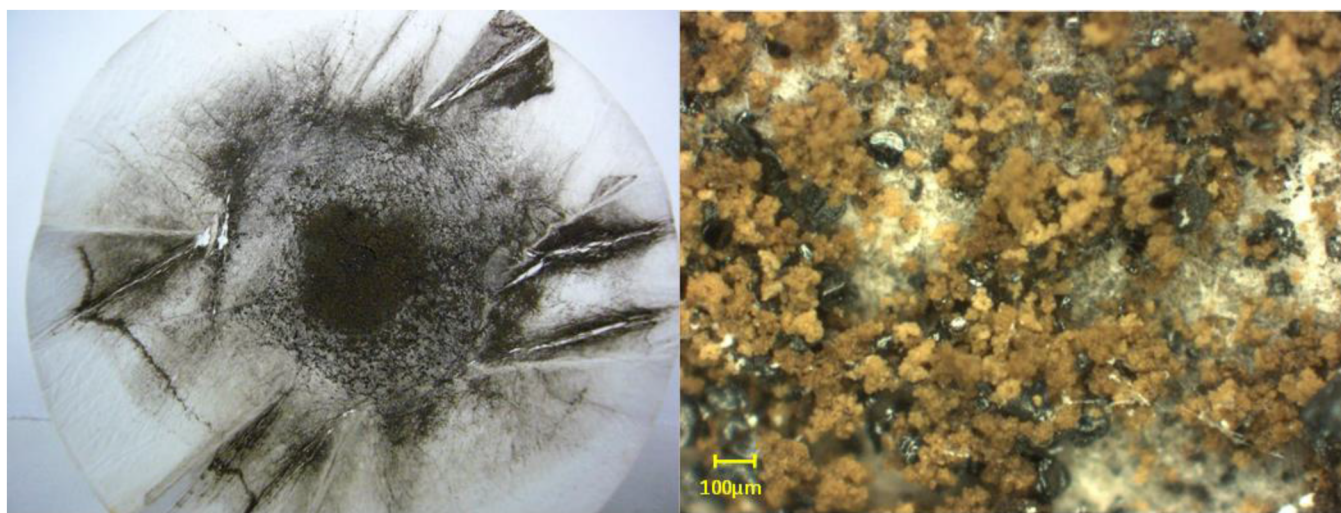


Figure 8—Photograph of the filtered emulsions (left), and micrographic view of the same sample (right). The black substances are interpreted to be asphaltene particles, and the brown substances are clay particles.

Overcoming Emulsion Problems

The operator carried out six field trials to mitigate emulsions from Well B before a successful remedy was found. Each trial is described, in chronological order, as follows and also summarized in [Table A-3 \(Appendix\)](#). It should be noted that some trials overlapped.

Raising the Processing Temperature

In general, the higher the temperature, the greater is the ability to resolve emulsions (Schramm 1992). Typical wellhead temperatures of the jet pump produced fluid are around 35°C. At the start of the jet pump operation, the fluid was heated to 60°C by the heat exchanger, before it flowed into the first separator (Separator A). This separator temperature was raised from 60 to 65°C in December 2014, however, no clear improvement in the BS&W ratio was observed. 65°C was the highest temperature that the first separator could achieve with the current configuration as the coating on the vertical gun barrel separator vessel, which is located downstream of the second separator (Separator B), was not rated for exposure to temperatures above 60°C.

Injecting Xylene into the Formation

The operator injected xylene into the formation twice in December 2014 and February 2015 because the well productivity dropped when the production rate was increased to 50 m³/d in November 2014. The operator speculated formation damage around the wellbore from asphaltene damage. The primary objective of these xylene injections was to remove the formation damage, while the secondary objective was to break emulsions. Even though both well productivity and the BS&W content marginally improved following these xylene injections, the duration of their effect lasted for only 1-2 weeks at a time.

Opening the Separator Dump Valve

A large amount of emulsion accumulated inside the separator vessel from March to September 2015, which seriously decreased the oil-water separation efficiency. The separator has two temperature sensors inside the vessel; the upper sensor reads the gas phase temperature, while the lower sensor reads the liquid phase temperature. The records of the two sensors are shown in Fig. A-1 (Appendix). From March to September 2015, the lower sensor reading frequently dropped to 40°C, while the upper sensor reading remained relatively constant, excluding the influence of outside temperature. This suggests that unmovable fluid, most likely emulsions, is accumulated at the bottom of the separator. The lower sensor was not reading the 'fresh' well-stream fluid anymore, instead it was reading the emulsion phase.

The operator opened a dump valve to drain emulsions almost every week during the summer of 2015. Once the separator was free of emulsion, the reading of the lower sensor returned to around 60°C (reading the 'fresh' well-stream fluid), and the BS&W also returned to 0 vol%. However, this treatment resulted in limited success with a short period of effectiveness. A new emulsion would accumulate inside the separator vessel requiring frequent opening of the dump valve, which is a highly unusual operational practice. Usually, the dump valve is opened once a year for annual inspection. This measure required a significant amount of work and was also expensive in terms of disposal costs. In addition, approximately 3 vol% of the produced oil was lost to the emulsion phase. Thus, opening the dump valve was only carried out as a temporary measure to maintain production.

Increasing Demulsifier Dosage Rate

During the natural flow production period, the chemical supplier stipulated 300 ppm as the recommended dosage rate for Well B. As the emulsion problem emerged during the jet pump operation, the operator attempted to optimize this concentration, experimenting with dosages between 300 and 550 ppm from May to November 2015. However, no clear improvement in the BS&W ratio was observed. Later, the chemical supplier suggested that excess demulsifier can often produce very stable emulsions.

Changing the Location of the Demulsifier Injection Port

The location of the demulsifier injection port was changed from downstream to upstream of the wellhead during July 2015. In other words, the demulsifier was injected into the power fluid, instead of the produced fluid. The intention was to minimize possible emulsion formation downhole as fluid travelled from the jet pump to the surface. However, no clear improvement was observed in the BS&W content. Therefore, two

weeks later, the location of the demulsifier injection port was returned to the downstream location of the wellhead.

Carrying Out Bottle Tests

Since none of the above field trials were considered effective, the last resort was to search for a more effective demulsifier. A total of 39 demulsifiers from six chemical companies were tested in the laboratory (bottle tests) during July 2015, as summarized in **Table 1**. The operator also tested five salts for a research purpose, namely sodium chloride (NaCl), potassium chloride (KCl), calcium chloride (CaCl_2), magnesium chloride (MgCl_2), and sodium sulfate (Na_2SO_4). The best demulsifier was selected for the field implementation.

Table 1—Summary of demulsifiers and salts evaluated in laboratory bottle tests.

Company	Number of Samples Tested	Demulsifiers/Salts
Company A	4	A-1 (Original), A-6, A-7 and A-8
Company B	1	B-1
Company C	3	C-1, C-2 and C-3
Company D	1	D-1
Company E	8	E-1 to E-8
Company F	22	F-1 to F-22
INPEX (the operator)	5	NaCl, KCl, CaCl_2 , MgCl_2 and Na_2SO_4
Total	44	

The bottle test procedure involved the following steps:

- Stop injection of demulsifier for three days, to collect a chemical-free oil sample.
- Collect an oil sample downstream of the heat exchanger (upstream of the separator).
- Measure BS&W content of this oil sample. Pour 100 ml of oil into a test tube and place it in a hot water bath heated to 60°C (equal to the processing temperature of the separator).
- Add demulsifier at the recommended concentration (200 ppm, if unspecified). The amounts of salts used for 100 ml of oil in additional bottle tests were NaCl (100 mg), KCl (100 mg), $\text{CaCl}_2 \cdot 2\text{H}_2\text{O}$ (133 mg), $\text{MgCl}_2 \cdot 6\text{H}_2\text{O}$ (215 mg), and Na_2SO_4 (100 mg).
- Shake the test tube by hand (200 times).
- Place the test tube back into the hot water bath.
- Record the amount of free water down and emulsions after 30 minutes (equivalent to the retention time at the separator).

The initial oil contained approximately 1.5 vol% of free water and no emulsion or sediment. The results of the bottle tests are illustrated in **Fig. 9**. The test tube without a demulsifier (Blank) yielded approximately 0.1 vol% of free water and no apparent emulsions as shown in **Fig. 10**. The original demulsifier (Demulsifier A-1) did not yield any free water but created approximately 3 vol% emulsion. This suggests that the emulsion problem experienced during 2014 and 2015 was likely caused by misuse of Demulsifier A-1. This scenario could have been avoided if a more appropriate chemical had been used. Demulsifier F-22 yielded approximately 1.4 vol% free water without emulsions; it was found to be the best chemical in our tests. Demulsifier F-22 was formulated specifically for Well B's production fluid; it is a blend of ethylene oxides

and propylene oxides block polymers, and a resin. Details of how the dose rate of F-22 was optimized for Well B are available in [Furuichi et al. \(2016\)](#).

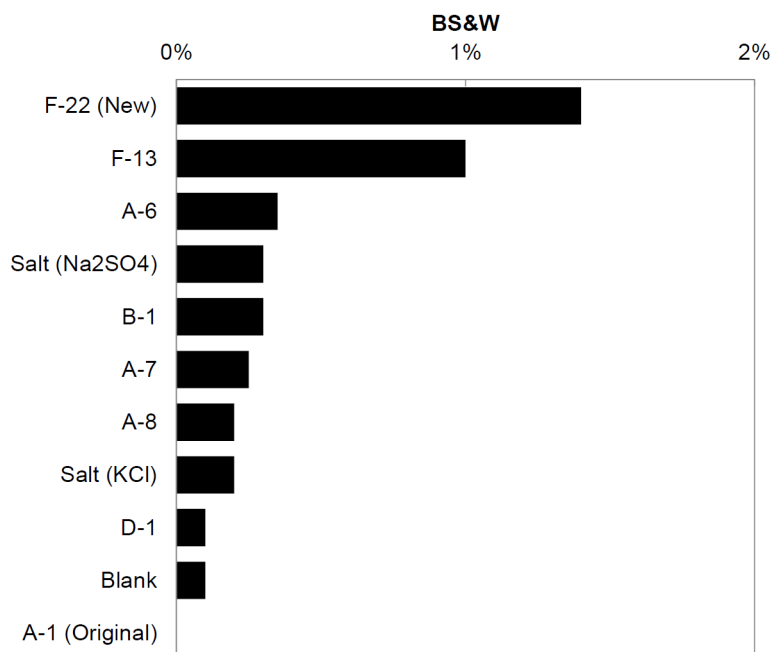


Figure 9—Results of the bottle tests. Demulsifier F-22 achieved the best performance, while the original Demulsifier A-1 did not yield any free water. Other chemicals that did not separate any free water are not shown in this bar chart.

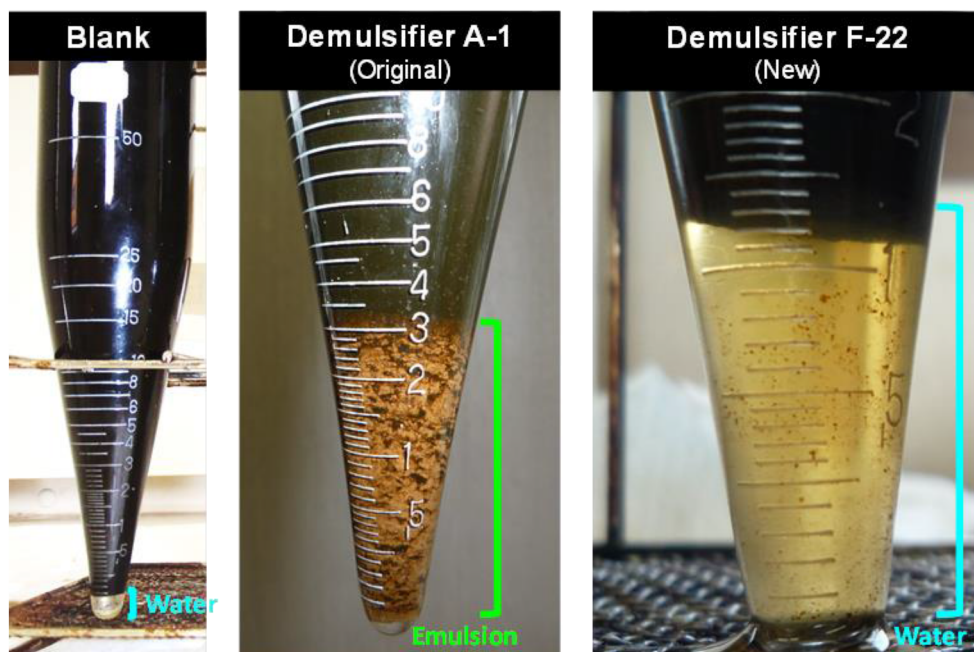


Figure 10—Bottle test result for the Blank, which yielded 0.1 vol% free water without emulsions (left); original Demulsifier A-1, which yielded 0 vol% free water and 3 vol% emulsions (middle); and the newly designed Demulsifier F-22, which yielded 1.4 vol% free water without emulsions (right).

For the three test tubes discussed above, the separated oil phase samples were subsequently analyzed to determine their water and emulsion contents by using toluene and a centrifuge. The Blank sample had 0 vol% water and 0.6 vol% emulsion contents in the separated oil phase. Demulsifier A-1 had only trace water and emulsion contents in the separated oil phase, while Demulsifier F-22 had 0.1 vol% water and 0.05 vol

% emulsion contents in the separated oil phase. The centrifuge test results suggest that Demulsifier A-1 was efficient at separating water from the oil phase, although it created an emulsion problem.

Our bottle tests revealed that 32 out of 39 commercial demulsifiers were ineffective in breaking the emulsions produced from Well B under current operating conditions. None of these chemicals yielded any free water on separation, and some even formed emulsions. **Fig. 11** shows a photograph of four of the ineffective demulsifier that were not able to separate any free water.

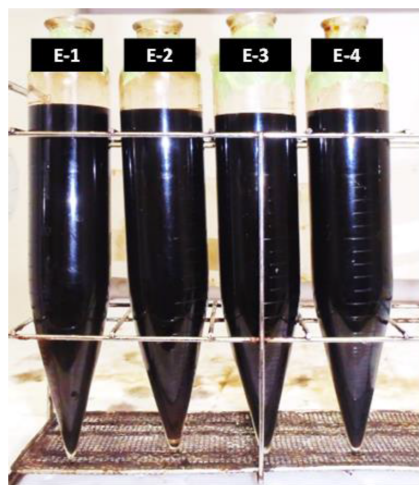


Figure 11—Example of the four demulsifiers (from left to right: Demulsifier E-1, E-2, E-3 and E-4) that yielded zero free water. In total, 32 out of 39 commercial demulsifiers were essentially ineffective.

A discussion of the use of salts to break emulsions is beyond the scope of this paper, and therefore, results are only briefly presented here. Na_2SO_4 and KCl yielded 0.3 vol% and 0.2 vol% of free water, respectively, while NaCl , CaCl_2 and MgCl_2 did not yield any free water, as shown in **Fig. 12**. No apparent emulsions were found in any of these five test tubes.



Figure 12—Bottle test results for five salts: NaCl , Na_2SO_4 , KCl , CaCl_2 , and MgCl_2 (from left to right).

Results

Soon after the operator switched from using Demulsifier A-1 to Demulsifier F-22 in October 2015, the oil-water separation efficiency dramatically improved; emulsions disappeared, and a zero BS&W content was continuously achieved in the sales oil. As a result, the operator regained the oil production rate of 50 m³/d. The production history of Well B after switching demulsifier is shown in [Appendix Fig. A-1](#).

Discussion: A Possible Emulsion Formation Mechanism

Even though the laboratory investigation of emulsion formation mechanism is currently in progress, a brief discussion on this subject is provided here. Following four elements were identified as the key contributors to the formation of Well B's emulsion. It is most likely that these four elements are all linked.

Introduction of Artificial Lift using a Jet Pump

The emulsion problem can be partly attributed to the introduction of a jet pump for two reasons. First, Well B's emulsion problem became apparent soon after the installation of the jet pump system. Second, shear environment in the jet pump system is greater than the natural flow system. It is well known that shear has a detrimental effect on emulsions ([Kokal 1999](#)).

Continued Use of the Original Demulsifier

The original demulsifier (A-1) was effective during the natural flow production period as shown in [Fig. 1](#). The well was relatively emulsion-free at various production rates ranging from 15 to 100 m³/d. Based on the observation that the emulsion problem became apparent soon after the introduction of jet pump, it is envisaged that Demulsifier A-1 was not effective for the new production configuration.

Increased Production Rate

[Fig. 3](#) showed that the emulsion problem emerged when the production rate was increased from 35 to 50 m³/d under demulsifier-free environment. It is envisaged that Well B's emulsion problem is partly attributed to the increased production rate. Higher production rate increases the shear and it may also result in insufficient retention time.

Presence of Asphaltene and Clay Particles

Asphaltene and clay particles were found in Well B's emulsion, as previously shown in [Fig. 8](#). The effect of these particles will be further investigated.

Conclusions

- Well B experienced poor oil-water separation, immediately after the switch from natural flow production to jet pump artificial lift. Large amounts of emulsion were observed inside the separator and stock tank. The operator was forced to reduce oil production rate from 50 to 35 m³/d.
- A number of field trials were carried out to mitigate the emulsion problem. The most efficient solution was to replace the original demulsifier (A-1) with a more effective one (F-22). After switching to the new demulsifier, the emulsions disappeared, and the operator regained oil production rate of 50 m³/d.
- Based on the field observations and the preliminary laboratory investigations, the emulsions that affected this well for a period of 1.5 years were most likely caused by the introduction of artificial lift augmented by the continued use of the original demulsifier chemical, the increased production rate, and the presence of asphaltene and clay particles.

- A lesson learned from this project was that emulsion treatment programs should be reviewed periodically, especially when operating conditions change.

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Appendix

Table A-1—Properties of oil in Field ‘M’.

Component	(mol%)
CO ₂	0.27
N ₂	0.15
C ₁	26.79
C ₂	6.80
C ₃	8.37
i-C ₄	1.43
n-C ₄	4.54
i-C ₅	1.81
n-C ₅	2.14
C ₆	5.47
C ₇₊	42.23
Molecular weight	102.5 g/mol
Bubble point pressure at reservoir temperature	13,204 kPa-abs (1,915 psia) (at 148°C/299°F)
Density at bubble point pressure and reservoir temperature	0.6436 g/cm ³ (at 148°C/299°F)
Asphaltene onset pressure at reservoir temperature (using near infra-red light transmittance)	23,512 kPa-abs (3,410 psia) (at 148°C/299°F)
Stock tank oil density at 15.6°C (60°F)	0.8445 g/cm ³ (API=36°)
Stock tank oil viscosity at 15.6°C (60°F)	2.8 cP
Stock tank oil wax appearance temperature	21°C
Stock tank oil SARA fractions:	
Saturates (wt%)	71.61
Aromatics (wt%)	16.06
Resins (wt%)	11.41
Asphaltene (wt%)	0.91

Table A-2—Properties of produced water in Field ‘M’.

Cation	mg/liter	Anion	mg/liter
Na ⁺	1,613	Cl ⁻	1,978
K ⁺	66	Br ⁻	12
Ca ²⁺	35	HCO ₃ ⁻	914
Mg ²⁺	1	OH ⁻	0
NH ₄ ⁺	15	CO ₃ ²⁻	6
Total Fe	0	SO ₄ ²⁻	72
		KMnO ₄	789
		HBO ₃ ²⁻	235
Total Dissolved Solids:			5,737 mg/liter
Density at 15.6°C:			1.001g/cc

Table A-3—Brief production history of Well B.

Date	Event
2008/1/29	Commercial production started using natural flow. Demulsifier A-1 was injected from Day 1.
2014/4/29	Natural flow stopped.
2014/7/11	Injected 25 m ³ of xylene into the formation.
2014/7/31	Re-started production using a jet pump at the rate of 35 m ³ /d.
2014/11/10	Oil rate increased to 50 m ³ /day.
2014/11/29	Production rate dropped to 35 m ³ /d to meet the sales oil BS&W specification.
2014/12/4	Separator temperature raised from 60 to 65°C.
2014/12/11	Injected 8.7 m ³ of xylene into the formation.
2015/2/23	Injected 55 m ³ of xylene into the formation.
2015/3/13	First opening of the separator dump valve.
2015/5/1	Started to gradually increase the demulsifier dosage rate from 300 ppm.
2015/7/8	Switched demulsifier injection point from downstream to upstream of the well.
2015/7/20	Returned demulsifier injection point from upstream to downstream of the well.
2015/7/23-7/24	Bottle tests using 39 demulsifiers from six vendors and five salts from the operator. Demulsifier F-22 was the best performer.
2015/12/10	Switched Demulsifier A-1 to Demulsifier F-22.
2016/1/8	Production rate increased to 50 m ³ /d, while zero BS&W was continuously achieved.

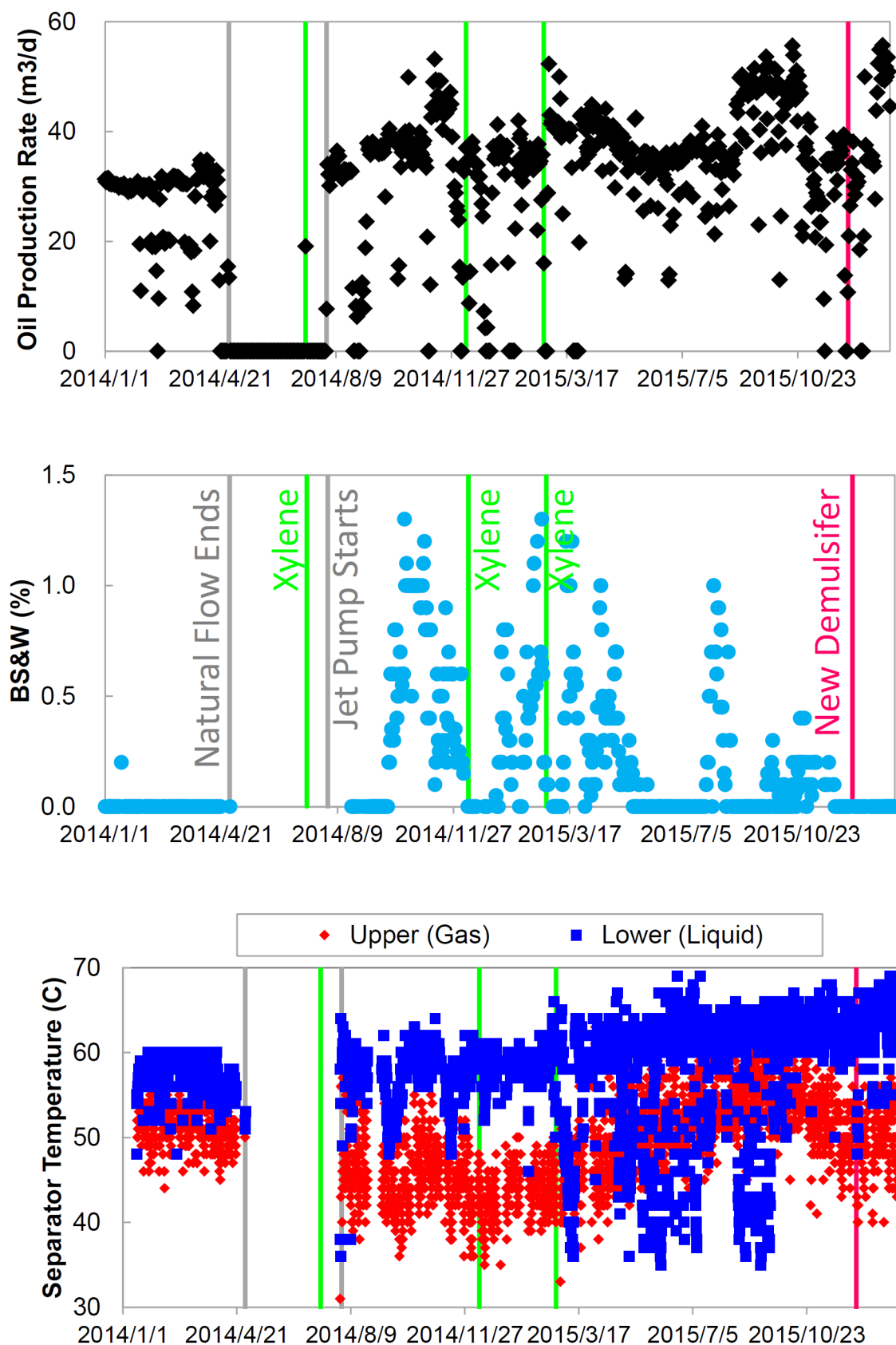


Figure A-1—History of Well B's oil production rate (top), basic sediment and water (BS&W) content in the sales oil (middle), and separator temperatures (bottom). In the bottom figure, the blue squares represent the liquid phase temperature, while the red diamonds represent the gas phase temperature. Two gray vertical lines represent the timing of end of the natural flow period and the start of jet pump production. Two green vertical lines represent xylene injection times into the formation. A pink vertical line represents the timing of injection of the new demulsifier F-22.